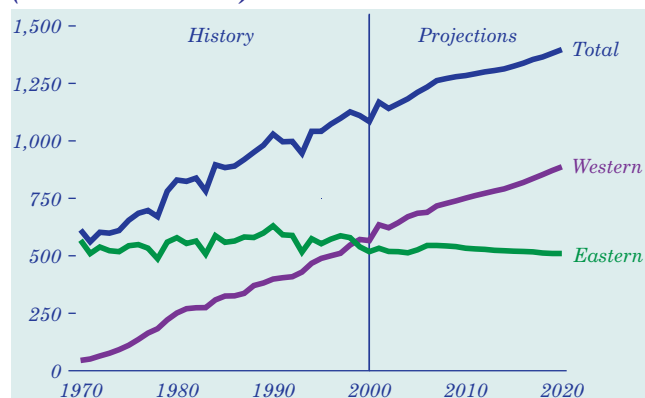# Coal Production and Prices

Emissions Caps Lead to More Use of Low-Sulfur Coal From Western Mines

Figure 86. Coal production by region, 1970-2020 (million short tons)

Minemouth Coal Prices Continue To Fall in the Projections

Figure 87. Average minemouth price of coal by region, 1990-2020 (2000 dollars per short ton)


Continued improvements in mine productivity (which have averaged 6.6 percent per year since 1980) are projected to cause falling real minemouth prices throughout the forecast. Higher electricity demand and lower prices, in turn, are projected to yield increasing coal demand, but the demand is subject to an overall sulfur emissions cap from CAAA90, which encourages progressively greater reliance on the lowest sulfur coals (from Wyoming, Montana, Colorado, and Utah).

The use of western coals can result in up to 85 percent lower sulfur dioxide emissions than the use of many types of higher sulfur eastern coal. As coal demand grows in the forecast, new coal-fired generating capacity is required to use the best available control technology: scrubbers or advanced coal technologies that can reduce sulfur emissions by 90 percent or more. Thus, even as the demand for low-sulfur coal is projected to grow, there are still expected to be market opportunities for higher sulfur coal throughout the forecast.

From 2000 to 2020, high- and medium-sulfur coal production is projected to remain essentially unchanged, declining from 576 to 571 million tons, and low-sulfur coal production is projected to rise from 509 to 827 million tons (2.5 percent per year). As a result of the competition between low-sulfur coal and post-combustion sulfur removal, western coal production is expected to continue its historical growth, reaching 887 million tons in 2020 (Figure 86), but its annual growth rate is projected to fall from the 8.8 percent achieved between 1970 and 2000 to 2.3 percent in the forecast period.
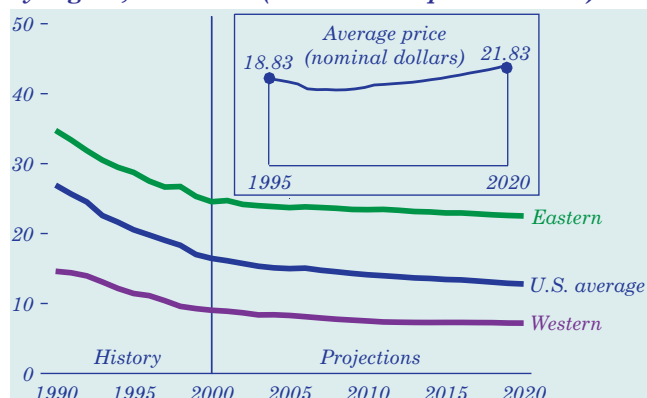
Minemouth coal prices declined by $6.88 per ton (in 2000 dollars) between 1970 and 2000, and they are projected to decline by 1.3 percent per year, or $3.66 per ton, between 2000 and 2020 (Figure 87). The price of coal delivered to electricity generators, which declined by approximately $1.89 per ton between 1970 and 2000, is projected to fall to $19.00 per ton in 2020—a 1.2-percent annual decline.

The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is expected to be maintained throughout the forecast. Average U.S. labor productivity (Figure 88) is projected to follow the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 88. Coal mining labor productivity by region, 1990-2020 (short tons per miner per hour)
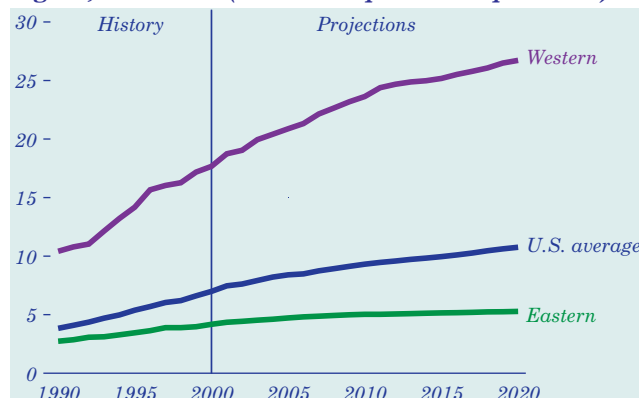
Labor Cost Contribution to Total Coal Prices Continues To Decline

*Figure 89. Labor cost component of minemouth coal prices, 1970-2020 (billion 2000 dollars)*
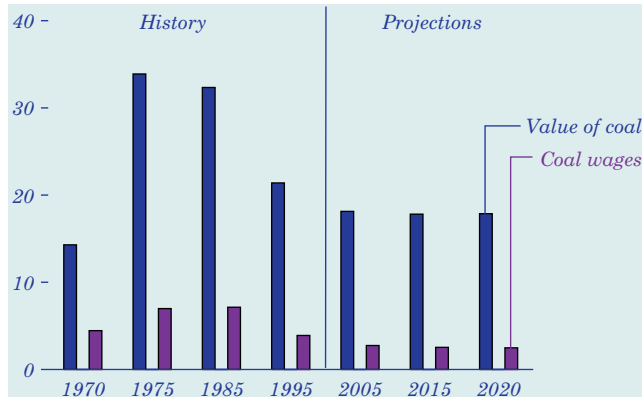
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity is also expected to be influenced by changing regional production shares. Competition from low sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. The boiler performance of western low-sulfur coal has been successfully tested by many electricity generators, and its use in eastern markets is projected to increase.

Eastern coalfields contain extensive reserves of higher sulfur coal in moderately thick seams suited to longwall mining. Continued penetration of technologies for extracting and hauling large volumes of coal in both surface and underground mining suggests that further reductions in mining cost are likely. Improvements in labor productivity have been, and are expected to remain, the key to lower coal mining costs.

As labor productivity improved between 1970 and 2000, the average number of miners working daily fell by 2.2 percent per year. With production increases and productivity improvements expected to continue through 2020, a further decline of 0.9 percent per year in the number of miners is projected. The share of wages (excluding irregular bonuses, welfare benefits, and payroll taxes paid by employers) in minemouth coal prices [91], which fell from 31 percent to 17 percent between 1970 and 2000, is projected to decline to 14 percent by 2020 (Figure 89).

High Labor Cost Assumption Leads to Lower Production in the East

Figure 90. Average minemouth coal prices in three mining cost cases, 1990-2020 (2000 dollars per short ton)
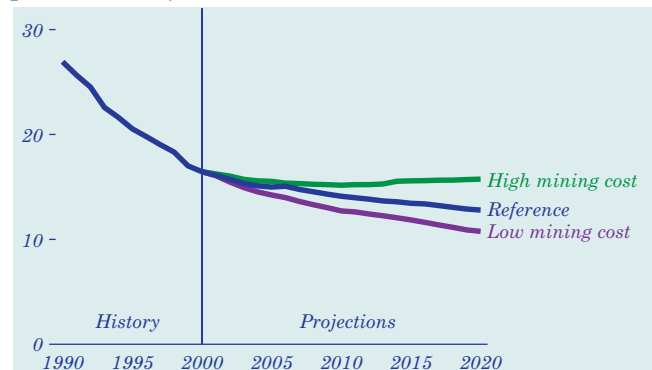
Alternative assumptions about future regional mining costs affect the projections for market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, projected minemouth prices, delivered prices, and the resulting regional coal production levels vary with changes in projected mining costs.

Productivity is assumed to increase by 2.2 percent per year through 2020 in the reference case, while wage rates and equipment costs are constant in 2000 dollars. The national minemouth coal price is projected to decline by 1.3 percent per year to $12.79 per ton in 2020 (Figure 90).

In the low mining cost case, productivity is assumed to increase by 3.7 percent per year, and real wages and equipment costs are assumed to decline by 0.5 percent per year [92]. As a result, the average minemouth price is projected to fall by 2.1 percent per year to $10.76 per ton in 2020 (16 percent less than projected in the reference case). Eastern coal production is projected to be 8 million tons higher in the low mining cost case than in the reference case in 2020, reflecting the higher labor intensity of mining in eastern coalfields. In the high mining cost case, productivity is assumed to increase by 0.6 percent per year, and real wages and equipment costs are assumed to increase by 0.5 percent per year. Consequently, the average minemouth price of coal is projected to fall by 0.2 percent per year to $15.74 per ton in 2020 (23 percent higher than in the reference case). Eastern production in 2020 is projected to be 9 million tons lower in the high mining cost case than in the reference case.

Coal Transportation Costs

Transportation Costs Are a Key Factor for Coal Markets

Figure 91. Projected change in coal transportation costs in three cases, 1999-2020 (percent)
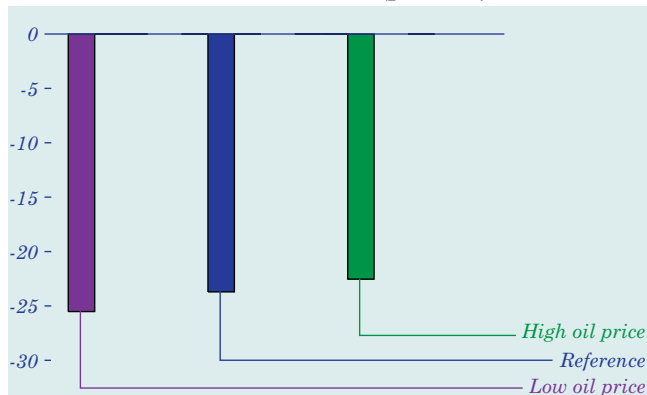

The competition between coal and other fuels, and among coalfields, is influenced by coal transportation costs. Increases in fuel costs affect transportation costs (Figure 91), but they are balanced to some extent by improvements in transportation fuel efficiency. As a result, in the reference case, average coal transportation rates are projected to decline by 1.3 percent per year between 1999 and 2020. Historically, the most rapid declines in coal transportation costs have occurred on routes originating in coalfields that have had the greatest declines in real minemouth prices. Railroads are likely to reinvest profits from increasing coal traffic to reduce transportation costs and, thus, expand the market for such coal. Therefore, coalfields that are most successful at improving productivity and lowering minemouth prices are likely to obtain the lowest transportation rates and, consequently, the largest markets at competitive delivered prices.

Mines in the Powder River Basin will require expansion of their train-loading capacities to meet the increase in demand resulting from the advent of Phase 2 of CAAA90, which became effective on January 1, 2000. The transition will require more low-sulfur coal than was projected in *AEO2001*, because demand for coal is expected to be higher. Any coal transportation problems associated with the increased shift to low-sulfur coal are expected to be temporary. Coal is transported from the Powder River Basin by two railroad systems, the Burlington Northern Santa Fe Railway and the Union Pacific Railroad.

Higher Economic Growth Would Favor Coal for Electricity Generation

Figure 92. Projected variation from reference case projections of coal demand for electricity generators in four cases, 2020 (million short tons)
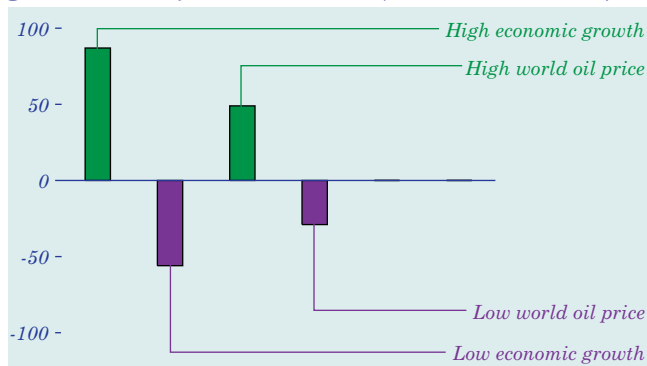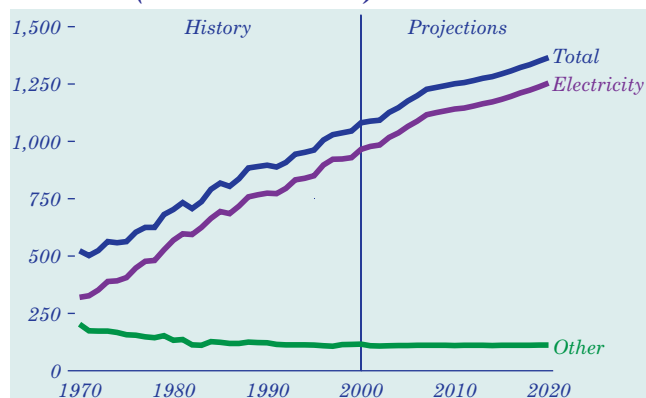

A strong correlation between economic growth and electricity use accounts for the variation in coal demand projections across the economic growth cases (Figure 92), with domestic coal consumption in 2020 projected to range from 1,303 to 1,462 million tons in the low and high economic growth cases, respectively. Of the difference, coal use for electricity generation is projected to make up 143 million tons. The difference in total projected coal production between the two economic growth cases is 158 million tons, of which 90 million tons (57 percent) is projected to be western production. Although western coal must travel up to 2,000 miles to reach some of its markets, it is expected to remain competitively priced in all regions except the Northeast when its transportation costs are added to its low minemouth price.

The low world oil price case projects 78 million tons less coal use for electricity generation in 2020 than the high world oil price case. Low oil prices encourage electricity generation from existing oil-fired units, reducing generation from other fuels. In the high world oil price case, both oil and natural gas prices are expected to be higher than in the reference case. As a result, new additions of coal-fired generating capacity are expected to be higher than in the reference case, as is coal-fired electricity generation, reducing both natural-gas-fired capacity additions and generation from natural-gas-fired plants.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 93. Electricity and other coal consumption, 1970-2020 (million short tons)

Industrial Steam Coal Use Rises, But Demand for Coking Coal Declines

Figure 94. Projected coal consumption in the industrial and buildings sectors, 2010 and 2020 (million short tons)


Domestic coal demand is projected to increase by 284 million tons in the reference case forecast, from 1,081 million tons in 2000 to 1,365 million tons in 2020 (Figure 93), because of projected growth in coal use for electricity generation. Coal demand in other domestic end-use sectors is projected to decline.

Coal consumption for electricity generation (excluding cogeneration) is projected to increase from 965 million tons in 2000 to 1,254 million tons in 2020 as the utilization of existing coal-fired generation capacity increases and, in later years, new capacity is added. The average utilization rate is projected to increase from 72 percent in 2000 to 84 percent in 2020. Because coal consumption (in tons) per kilowatthour generated is higher for subbituminous and lignite than for bituminous coals, the shift to western coal is projected to increase the tonnage per kilowatthour of generation in the Midwest and Southeast regions. In the East, generators are expected to shift to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per ton.

Although coal is projected to maintain its fuel cost advantage over both oil and natural gas, gas-fired generation is expected to be the most economical choice for construction of new power generation units in most situations, when capital, operating, and fuel costs are considered. Between 2005 and 2020, rising natural gas costs, increasing demand for electricity, and retirements of existing nuclear and fossil-fired steam capacity are projected to result in increasing demand for coal-fired baseload capacity.
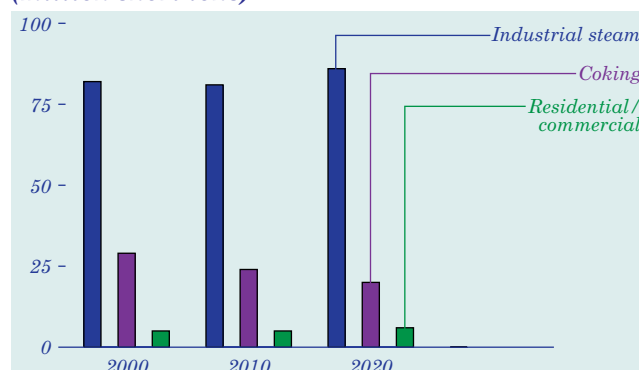
In the non-electricity sectors, a projected increase of 4 million tons in industrial steam coal consumption between 2000 and 2020 (0.2-percent annual growth) is expected to be offset by a decrease of 9 million tons in coking coal consumption (Figure 94). Increasing consumption of industrial steam coal is projected to result primarily from greater use of existing coal-fired boilers in energy-intensive industries.

The projected decline in domestic consumption of coking coal results from the expected displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 1.9 percent per year through 2020, but domestic production of coking coal is expected to be stabilized, in part, by sustained levels of export demand.

Although total energy consumption in the combined residential and commercial sectors is projected to grow by 1.3 percent per year, most of the growth is expected to be captured by electricity and natural gas. Coal consumption in the residential and commercial sectors is projected to remain constant, accounting for less than 1 percent of total U.S. coal demand in the forecast.

Coal Exports

U.S. Coal Exports to Europe and Asia Are Projected To Remain Stable

Figure 95. Projected U.S. coal exports by destination, 2010 and 2020 (million short tons)
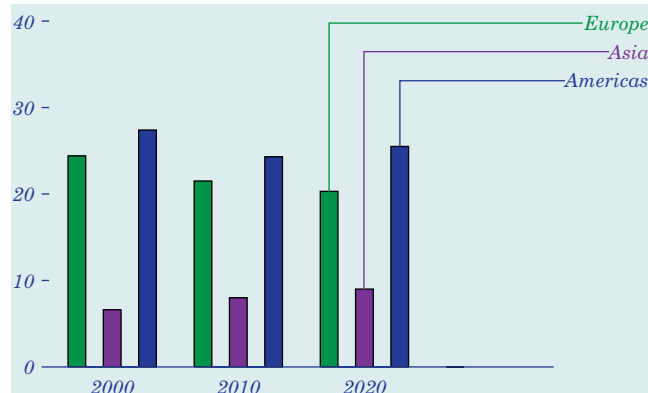

U.S. coal exports declined sharply between 1998 and 1999, from 78 million tons to 58 million tons, but are projected to remain relatively stable over the forecast horizon, settling at 55 million tons by 2020 (Figure 95). Australian and South African coal export prices dropped substantially in 1999, displacing U.S. coal exports to Europe and Asia. Price cuts by Australia, the world's leading coal exporter, were attributed to both strong productivity growth and a favorable exchange rate against the U.S. dollar.

The U.S. share of total world coal trade is projected to decline from 10 percent in 2000 to 8 percent by 2020 as international competition intensifies and demand for coal imports in Europe and the Americas grows more slowly or declines. From 2000 to 2020, U.S. steam coal exports are projected to decline from 26 million tons to 20 million tons, despite substantial projected growth in world steam coal trade. Steam coal exports from Australia, South Africa, China, and Indonesia are expected to increase in response to growing import demand in Asian countries. Increasing exports from South America (Colombia and Venezuela) are expected to lead to a gradual increase in that region's share of the market for steam coal both in Europe and in the Americas.

U.S. coking coal exports are projected to increase slightly, from 33 million tons in 2000 to 35 million tons in 2020. A small increase in the world trade in coking coal is expected, primarily in Asia. Australia is expected to capture an increasing share of the international market for coking coal because of its proximity to Asian importers and its ample reserves of coking coal.

Low-Sulfur Coal Continues To Gain Share in the Generation Market

Figure 96. Projected coal production by sulfur content, 2010 and 2020 (million short tons)
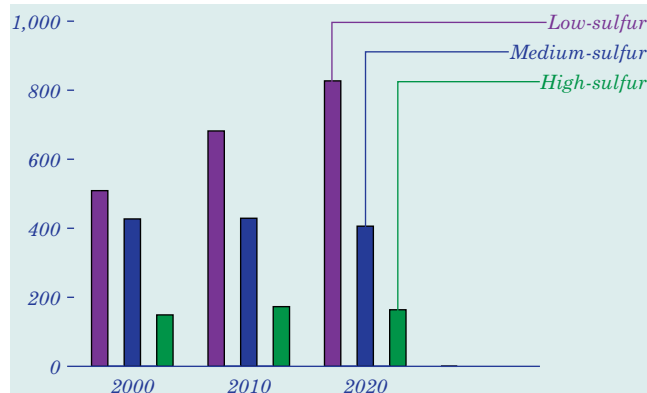

Phase 1 of CAAA90 required 261 coal-fired generating units to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which took effect on January 1, 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired with coal, oil, and gas. The program affects existing units serving generators over 25 megawatts capacity and all new units [93].

With relatively modest capital investments many generators can blend very low sulfur subbituminous and bituminous coal in Phase 1 affected boilers. Such fuel switching often generated sulfur dioxide allowances beyond those needed for Phase 1 compliance, and the excess allowances generated during Phase 1 were banked for use in Phase 2 or sold to other generators. (The proceeds of such sales can be seen as further reducing fuel costs for the seller.) In the forecast, fuel switching for regulatory compliance and for cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 96). The main sources of low-sulfur coal are the Central Appalachian, Powder River Basin, and Rocky Mountain regions, and coal imported from Colombia.

Coal users may incur additional costs in the future if environmental problems associated with nitrogen oxides, particulate emissions, and possibly mercury and carbon dioxide emissions from coal combustion are monetized and added to the costs of coal combustion. See "Issues in Focus," pages 37-50, for discussion of EIA analyses of multi-emissions reductions.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 97. Projected carbon dioxide emissions by sector and fuel, 2005-2020 (million metric tons carbon equivalent)
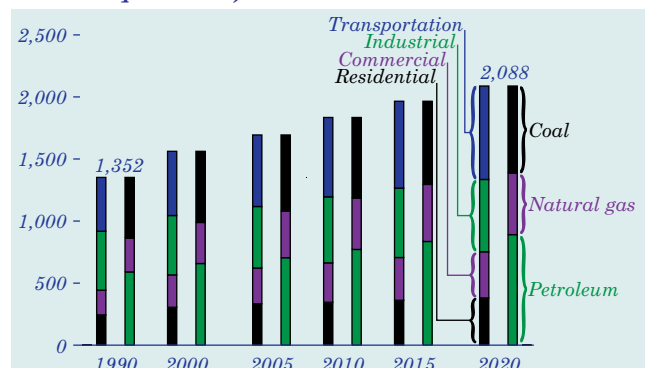
Carbon dioxide emissions from energy use are projected to increase on average by 1.5 percent per year from 2000 to 2020, to 2,088 million metric tons carbon equivalent (Figure 97), and emissions per capita are projected to grow by 0.6 percent per year.

Carbon dioxide emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.1 percent per year, reflecting the ongoing trends of electrification and penetration of computers, electronics, and appliances. Significant growth in office equipment and computers, as well as floorspace, is also projected for the commercial sector. As a result, carbon dioxide emissions from the commercial sector are projected to increase by 1.8 percent per year.

In the transportation sector, carbon dioxide emissions are projected to grow at an average annual rate of 1.9 percent as a result of projected increases in vehicle-miles traveled and freight and air travel, with small increases in average vehicle efficiency. Industrial emissions are projected to grow by 1.0 percent per year, as shifts to less energy-intensive industries and efficiency gains are projected to moderate growth in energy use.

In all sectors, potential growth in carbon dioxide emissions is expected to be moderated by efficiency standards, voluntary efficiency programs, and improvements in technology. Carbon dioxide mitigation programs, further improvements in technology, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Petroleum Products Lead Carbon Dioxide Emissions From Energy Use

Figure 98. Projected carbon dioxide emissions per unit of gross domestic product, 1990-2020 (metric tons carbon equivalent per million dollars)
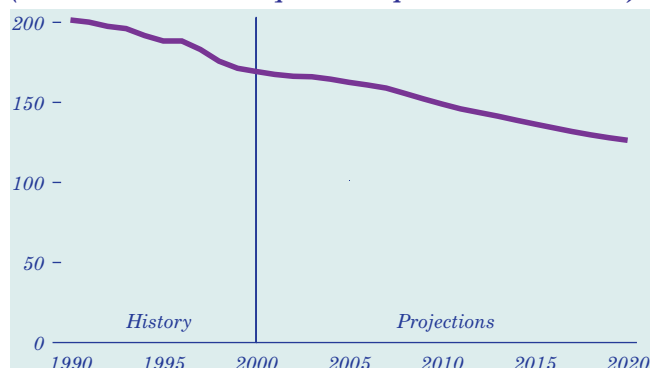
Petroleum products are the leading source of carbon dioxide emissions from energy use. In 2020, petroleum is projected to account for 891 million metric tons carbon equivalent, a 43-percent share of the projected total. About 82 percent (731 million metric tons carbon equivalent) of the emissions from petroleum use are expected to result from transportation fuel use, which could be reduced with less travel or more rapid development and adoption of higher efficiency or alternative-fuel vehicles.

Coal is the second leading source of carbon dioxide emissions, projected to produce 701 million metric tons carbon equivalent in 2020, or 34 percent of the total. The coal share is projected to decline from 37 percent in 2000, because coal consumption is expected to increase at a slower rate through 2020 than consumption of petroleum and natural gas. Most of the increases in emissions from coal use result from electricity generation.

In 2020, natural gas use is projected to produce a 24-percent share of total carbon dioxide emissions, 496 million metric tons carbon equivalent. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2020, at an average annual rate of 2.0 percent; but natural gas produces only half the emissions of coal per unit of input.

As the economy becomes more energy-efficient, its carbon intensity also declines. Between 2000 and 2020, the carbon intensity of the economy is expected to decline at an average rate of 1.5 percent per year (Figure 98).

Carbon Dioxide Emissions

Electricity Use Is Another Major Cause of Carbon Dioxide Emissions

Figure 99. Projected carbon dioxide emissions from electricity generation by fuel, 2005-2020 (million metric tons carbon equivalent)


Electricity generation is a major source of carbon dioxide emissions. Although electricity produces no emissions at the point of use, generation (excluding cogeneration) accounted for 38 percent of total carbon dioxide emissions in 2000, and its share is expected to remain the same in 2020. Coal is projected to account for 49 percent of electricity generation in 2020 (excluding cogeneration) and to produce 80 percent of electricity-related carbon dioxide emissions (Figure 99). In 2020, natural gas is projected to account for 28 percent of electricity generation (excluding cogeneration) but only 19 percent of electricity-related carbon dioxide emissions.

Between 2000 and 2020, 10 gigawatts of nuclear capacity is projected to be retired, resulting in a 7-percent decline in nuclear generation. To make up for the loss of nuclear capacity and meet rising demand, 342 gigawatts of new fossil-fueled capacity (excluding cogeneration) is projected to be needed. Increased generation from fossil fuels is expected to raise carbon dioxide emissions from electricity generation (excluding cogeneration) by 204 million metric tons carbon equivalent, or 35 percent, from 2000 levels. Generation from renewable technologies (excluding cogeneration) is projected to increase by 86 billion kilowatthours, or 27 percent, between 2000 and 2020 but is not expected to be sufficient to offset the projected increase in generation from fossil fuels.

The projections include announced activities under the Climate Challenge program, such as fuel switching, repowering, life extension, and demand-side management, but they do not include offset activities, such as reforestation.

Emissions Projections Change With Economic Growth Assumptions

Figure 100. Projected carbon dioxide emissions in three economic growth cases, 1990-2020 (million metric tons carbon equivalent)
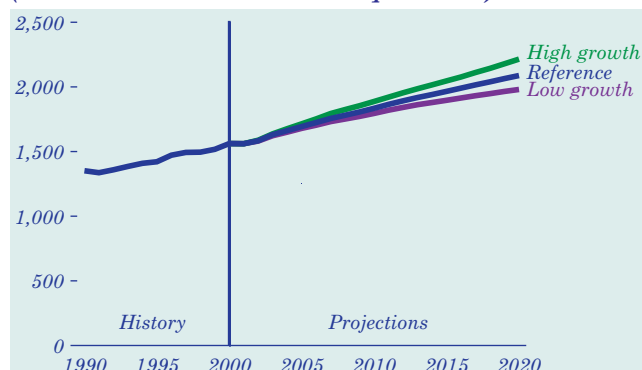

The high economic growth case assumes higher growth in population, labor force, and productivity than in the reference case, leading to higher industrial output, lower inflation, and lower interest rates. GDP growth in the high growth case averages 3.4 percent per year from 2000 to 2020, as compared with 3.0 percent per year in the reference case. In the low economic growth case, which assumes lower growth in population, labor force, and productivity, GDP growth averages 2.4 percent per year.

Higher projections for manufacturing output and income increase the demand for energy services in the high economic growth case, and energy consumption totals 138.2 quadrillion Btu in 2020, 6 percent higher than in the reference case. As a result, carbon dioxide emissions are projected to reach 2,215 million metric tons carbon equivalent in 2020, also 6 percent higher than in the reference case (Figure 100). Total energy intensity, measured as primary energy consumption per dollar of GDP, declines by 1.7 percent per year in the high growth case, as compared with 1.5 percent in the reference case. With more rapid projected growth in energy consumption, there is expected to be a greater opportunity to turn over and improve the stock of energy-using technologies, increasing the overall efficiency of the capital stock.

In the low growth case, energy consumption reaches 124.1 quadrillion Btu in 2020, 5 percent lower than projected in the reference case, and carbon dioxide emissions in 2020 are also 5 percent lower at 1,980 million metric tons carbon equivalent. Energy intensity is projected to decline at a rate of 1.3 percent annually through 2020 in the low growth case.

Technology Advances Could Reduce Carbon Dioxide Emissions

Figure 101. Projected carbon dioxide emissions in three technology cases, 1990-2020 (million metric tons carbon equivalent)
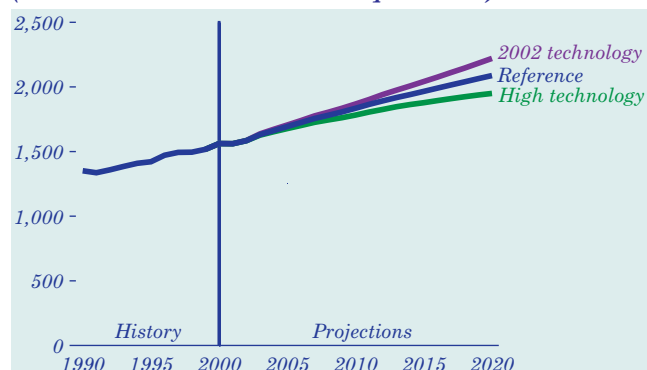

The reference case assumes continuing improvement in energy-consuming and producing technologies, consistent with historic trends, as a result of ongoing research and development. In the high technology case it is assumed that increased spending on research and development will result in earlier introduction, lower costs, and higher efficiencies for end-use technologies than assumed in the reference case. The costs and efficiencies of advanced fossil-fired and new renewable generating technologies are also assumed to improve from reference case values [*94*]. Energy intensity is expected to decline on average by 1.8 percent per year through 2020 in the high technology case, as compared with 1.5 percent in the reference case. As a result, energy consumption is projected to be 6 percent lower than in the reference case in 2020, at 123.5 quadrillion Btu, and carbon dioxide emissions are projected to be 7 percent lower than in the reference case, at 1,950 million metric tons carbon equivalent (Figure 101).

The 2002 technology case assumes that future equipment choices will be made from the equipment and vehicles available in 2002; that new building shell and plant efficiencies will remain at their 2002 levels; and that advanced generating technologies will not improve over time. Energy efficiency improves in the 2002 technology case as new equipment is chosen to replace older stock and the capital stock expands, and energy intensity declines by 1.3 percent per year through 2020. Energy consumption reaches 136.9 quadrillion Btu in 2020 in the 2002 technology case, and carbon dioxide emissions in 2020 are projected to be 6 percent higher than in the reference case, at 2,221 million metric tons carbon equivalent.

Moderate Growth in Methane Emissions Is Expected

Figure 102. Projected methane emissions from energy use, 2005-2020 (million metric tons carbon equivalent)
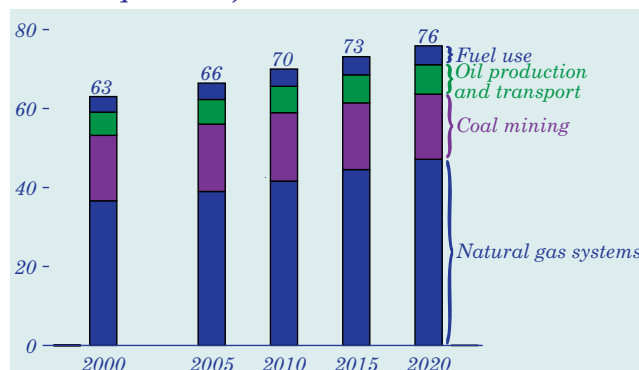
Methane emissions from energy use are projected to increase at an average rate of 0.9 percent per year from 2000 to 2020, somewhat slower than the 1.5-percent projected growth rate for carbon dioxide emissions. Based on global warming potential, methane is the second largest component of U.S. man-made greenhouse gas emissions after carbon dioxide, and it is one of the six gases covered in the Kyoto Protocol. In 2000, methane accounted for 9 percent of total U.S. greenhouse gas emissions of 1,906 million metric tons carbon equivalent. About a third of U.S. methane emissions are related to energy activities, mostly from energy production and transportation and to a much smaller extent from fuel combustion. Other sources of methane emissions include waste management, agriculture, and industrial processes.

Much of the projected increase in energy-related methane emissions is tied to increases in oil and gas use (Figure 102). The fugitive methane emissions that occur during natural gas production, processing, and distribution are expected to increase, despite declines in the average rate of emissions per unit of production. Emissions related to oil production and, to a lesser extent, refining and transport are also expected to increase. Coal-related methane emissions are expected to decline, with coal production from methane-intensive underground mining projected to remain flat over the forecast period while progress in the recovery of vented gas continues. About 6 percent of methane emissions in 2000 resulted from wood and fossil fuel combustion. A 22-percent increase is projected by 2020, with residential use of wood as a fuel expected to remain at about its 2000 level.

Emissions from Electricity Generation

Scrubber Retrofits Will Be Needed To Meet Sulfur Emissions Caps

Figure 103. Projected sulfur dioxide emissions from electricity generation, 2000-2020 (million tons)

CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons per year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million tons per year may not be reached until after 2010. About 97 percent of the SO_2 produced by generators results from coal combustion and the rest from residual oil.

CAAA90 called for the reductions to occur in two phases, with larger (more than 100 megawatts) and higher emitting (more than 2.5 pounds per million Btu) plants making reductions first. In Phase 1, 261 generating units at 110 plants were issued tradable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances may also be banked for use in future years. Switching to lower sulfur subbituminous coal was the option chosen by most generators, as only about 12 gigawatts of capacity had been retrofitted by 1995.

In Phase 2, beginning in 2000, emissions constraints on Phase 1 plants are tightened, and limits are set for the remaining 2,500 boilers at 1,000 plants. With allowance banking, emissions are projected to decline from 11.9 million tons in 1995 to 11.1 million in 2000 (Figure 103). With the SO_2 emissions cap tightened in 2000 and after, the price of allowances is projected to reach $198 per ton by 2005. At that price level, 23 gigawatts of capacity is expected to be retrofitted with scrubbers to meet the Phase 2 goal.

Nitrogen Oxide Emissions Are Projected To Stay Below 2000 Levels

Figure 104. Projected nitrogen oxide emissions from electricity generation, 2000-2020 (million tons)

Nitrogen oxide (NO_x) emissions from U.S. electricity generation are projected to fall through 2005, as new legislation takes effect (Figure 104). The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months. The CAAA90 NO_x reduction program called for reductions at electric power plants in two phases, the first in 1995 and the second in 2000. The second phase of CAAA90 resulted in NO_x reductions of 1.4 million tons between 1999 and 2000.

Even after the CAAA90 regulations have taken effect, further effort may be needed in some areas. For several years the EPA and the States have studied the movement of ozone from State to State. The States in the Northeast have argued that emissions from coal plants in the Midwest make it difficult for them to meet national air quality standards for ground-level ozone, and they have petitioned the EPA to force the coal plant operators to reduce their emissions more than required under current rules.

Interpretations of ozone transport studies have been controversial. In September 1998 the EPA issued a rule, referred to as the Ozone Transport Rule (OTR), to address the problem. The OTR called for capping NO_x emissions in 22 Midwestern and Eastern States during the summer season, and following a court challenge, emissions limits were finalized for 19 States. These limits, which are included in the projections, increase the operating costs of coal-fired and, to a lesser extent, natural-gas-fired units.